DIRECT TESTIMONY OF KENNETH SERCY

ON BEHALF OF THE SOUTHERN ALLIANCE FOR CLEAN ENERGY AND SOUTH CAROLINA COASTAL CONSERVATION LEAGUE

DOCKET NO. 2021-88-E

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Kenneth Sercy. I am an independent electric sector consultant, and my business address is 9042 East 24th Place #102, Denver, CO 80238.

Q. ON WHOSE BEHALF ARE YOU PROVIDING TESTIMONY?

A. I am providing testimony on behalf of the South Carolina Coastal Conservation League ("CCL") and the Southern Alliance for Clean Energy ("SACE").

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I have a Bachelor of Science degree from Clemson University and a Master of Environmental Management degree from Duke University, and ten years of experience in electricity markets, policy, and regulation focused on engineering-economic modeling and cost-of-service ratemaking. I have designed, run, and evaluated a variety of electric power modeling analyses including production cost, capacity expansion, and avoided cost and related cost-effectiveness tests, and have evaluated cost recovery, resource planning, asset certification, program and tariff design in more than sixty regulated utility proceedings, primarily in South Carolina. My professional experience also includes modeling renewable

energy project economics and conducting market research on competitive procurements, power purchase agreement terms, and interconnection queues.

While studying at Duke University, I worked for two years at the Nicholas Institute for Environmental Policy Solutions supporting energy modeling research using the U.S. Department of Energy's National Energy Modeling System. After graduating from Duke in 2012, I served as CCL's Utility Regulation Specialist for five years, where I managed the organization's work before the South Carolina Public Service Commission ("Commission") and supported a variety of electric sector policy objectives. Since 2018, I have worked as an independent clean energy consultant providing expert witness testimony, regulatory analysis and guidance, and market research relating to renewable energy and energy storage development, in both traditionally regulated and competitive wholesale regions of the U.S. I have co-authored technical papers published by Clemson University's Strom Thurmond Institute, the North Carolina Sustainable Energy Association, and the journal *Energy Policy*. A copy of my *curriculum vitae* is included as **Exhibit KS-1**.

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY TO THIS COMMISSION?

A. Yes, I provided testimony on behalf of the Carolinas Clean Energy Business Association[1] in Docket No. 2019-226-E regarding Dominion Energy South Carolina's ("DESC" or "the Company") 2020 Integrated Resource Plan ("IRP"). I also provided testimony on behalf of the CCL and the SACE in Docket No. 2019-365-E regarding competitive procurement of renewable energy.

[1] Formerly the South Carolina Solar Business Alliance.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony first provides background information on South Carolina's implementation of the Public Utilities Regulatory Policy Act ("PURPA"). I then describe several concerns I have with DESC's avoided cost rate proposals under two broad categories: avoided energy and avoided capacity. I also propose improvements to DESC's methodologies and assumptions that will better align DESC's avoided cost rates with PURPA and the Energy Freedom Act.

Q. PLEASE PROVIDE A BRIEF SUMMARY OF YOUR CONCLUSIONS AND RECOMMENDATIONS.

A. I conclude that DESC's avoided cost rate proposals fail to meet the statutory standards due to certain unreasonable calculation inputs, multiple discriminatory elements, and several major transparency issues. I recommend curing these problems through adoption of reasonable calculation inputs and elimination of the discriminatory aspects of the proposal.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

I. Background on the Energy Freedom Act and PURPA in South Carolina

II. Avoided Energy Rates

III. Avoided Capacity Rates

IV. Transparency in DESC's Application and Testimony

V. Conclusions and Recommendations

I. BACKGROUND ON THE ENERGY FREEDOM ACT AND PURPA IN SOUTH CAROLINA

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE ENERGY FREEDOM ACT OF 2019 ("EFA") PROVISIONS RELATING TO PURPA AND AVOIDED COST RATEMAKING.

A. The EFA provisions relating to PURPA and avoided cost ratemaking cover a variety of topics including parameters for docketed avoided cost review proceedings, third-party Commission consultants, standard offer tariffs, standardized forms used by utilities and small power producers, requirements related to avoided cost rates and methodologies, and transparency.[2] Section 58-41-20 of the EFA also provides that avoided costs must be consistent with PURPA, stating that

> [a]ny decisions by the commission shall be just and reasonable to the ratepayers of the electrical utility, in the public interest, consistent with PURPA and the Federal Energy Regulatory Commission's implementing regulations and orders, and nondiscriminatory to small power producers; and shall strive to reduce the risk placed on the using and consuming public.[3]

Section 58-41-20 also includes provisions regarding transparency and fair and non-discriminatory rates that are of particular relevance to this proceeding, as discussed further below.

Q. HOW DOES THE EFA ADDRESS FAIR AND NON-DISCRIMINATORY RATES?

A. The EFA requires that "the commission shall treat small power producers on a fair and equal footing with electrical utility-owned resources…"[4] This includes, for example, "ensuring that rates for the purchase of energy and capacity fully and accurately reflect the

[2] S.C. Code Ann. § 58-41-20.
[3] S.C. Code Ann. § 58-41-20 (A).
[4] S.C. Code Ann. § 58-41-20 (B).

electrical utility's avoided costs,"[5] while allowing "[a]voided cost methodologies approved by the commission [to] account for differences in costs avoided based on the geographic location and resource type of a small power producer's qualifying small power production facility."[6]

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS ABOUT PURPA IMPLEMENTATION IN SOUTH CAROLINA.

A. The EFA of 2019 addresses PURPA implementation at length and covers many topics related to review of the avoided cost rates available to small power producers and accompanying standard contract forms. These rates must be reasonably transparent, accurately reflect the utility's avoided costs, and treat small power producers on equal footing with utility resources.

Q. DOES DESC'S PROPOSAL MEET THESE STANDARDS?

A. No, it does not. The following sections of my testimony, on avoided energy and avoided capacity rates, describe how DESC falls short of these standards. I also offer solutions and make recommendations in several areas that would help ensure compliance with the EFA.

II. AVOIDED ENERGY RATES

Q. WHAT CONCERNS DO YOU HAVE WITH DESC'S PROPOSED AVOIDED ENERGY RATES?

A. DESC's proposed avoided energy rates do not "fully and accurately reflect the electrical utility's avoided costs."[7] The natural gas price assumptions underlying the

[5] S.C. Code Ann. § 58-41-20 (B)(1).
[6] S.C. Code Ann. § 58-41-20 (B)(3).
[7] S.C. Code Ann. § 58-41-20 (B)(1).

proposed energy rates are unreasonably low and the load forecast also appears to be contributing to an underestimation of the costs avoided by qualifying facilities ("QFs") such as independent solar facilities. It is also not clear from DESC's application and testimony whether the proposed pricing periods are just, reasonable, and nondiscriminatory as required by state and federal law. Finally, I have concerns with the eligibility for the "non-solar QF" energy rates, which implicates the EFA's nondiscriminatory standard and to the provision on accounting for differences in costs avoided based on the QF's geographic location and resource type, and in turn to accurately reflecting avoided costs.

Q. PLEASE PROVIDE ADDITIONAL DETAIL ABOUT THE MODELING DESC USED TO DEVELOP ITS PROPOSED AVOIDED ENERGY RATES.

A. DESC used a production cost modeling platform called PLEXOS to simulate the operation of its system on an hourly basis, in a base case and a change case. In the base case, the PLEXOS software simulates the system including "DESC's existing and future fleet of generators and the hourly load profile to be served by these generators, as well as the solar facilities with which DESC has executed a power purchase agreement,"[8] whereas in the change case, the same system is simulated "except that a zero-cost purchase transaction modeled after the appropriate 100 MW energy profile is assumed."[9] DESC then uses the cost differential between these two cases as the avoided energy cost attributable to the QF. While this is a reasonable overall approach, it is important to recognize that production cost software platforms such as PLEXOS are complex models with thousands of data inputs. The cost results that PLEXOS produces are only reliable to the extent that

[8] Direct Testimony of James Neely at 6, Docket No. 2021-88-E (June 29, 2021).
[9] *Id.*

the inputs utilized are reasonable. In other words, rates will not "fully and accurately reflect the electrical utility's avoided costs" if unreasonable inputs are used.

Two key inputs that deserve scrutiny are natural gas prices and the load forecast. The natural gas price assumptions are the major determinant of the cost of generating electricity from gas-fired generating units, which supply a very large proportion of DESC's system energy. The assumed gas prices impact unit commitment and dispatch patterns on DESC's system and would be expected to have a major impact on avoided energy costs across many hours. Similarly, the load determines how much demand the system must meet in each hour, which directly impacts the least-cost resources dispatched in each hour for each year modeled; this in turn modifies the marginal cost of generation.

Additional elements of the underlying energy modeling should be carefully reviewed to ensure an accurate reflection of the utility's avoided costs. These include the expansion plan assumed in the production cost modeling runs, other fuel price and variable cost assumptions, and generating unit operating parameters. If any of these inputs are unrealistic or do not reflect reasonable expectations for ongoing system operations, the resulting avoided cost rates will in turn be unreasonable.

Q. DID DESC USE REASONABLE NATURAL GAS PRICE ASSUMPTIONS IN ITS PROPOSAL?

A**.** No. DESC used a methodology for forecasting natural gas prices that this Commission recently rejected in Order No. 2020-832. The Commission also concluded in that order that the gas prices produced by DESC's methodology were too low.

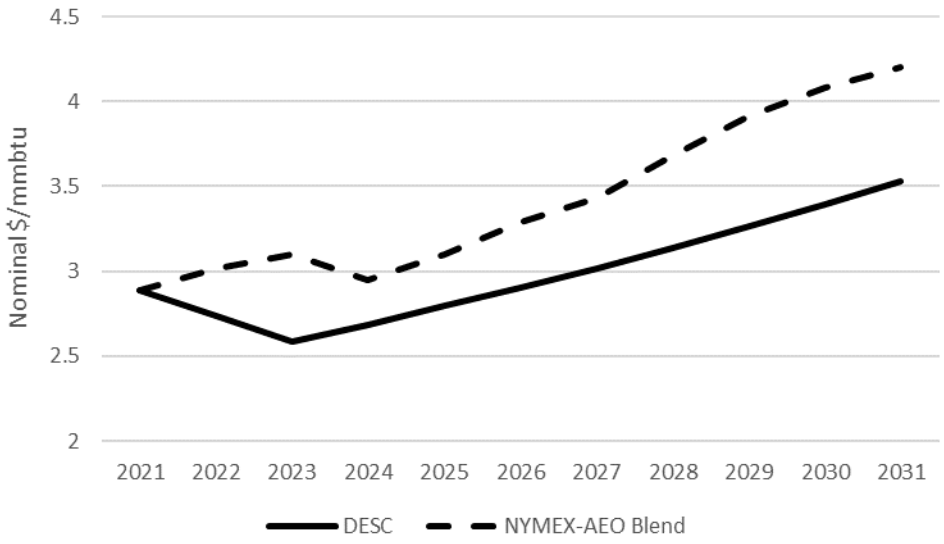
Specifically, DESC utilized three years of NYMEX natural gas futures prices, and thereafter escalated the annual price by 3.959% "based on EIA AEO reference case gas

price forecast."[10] However, in Order No. 2020-832, the Commission ruled that DESC must directly use the US Energy Information Administration ("EIA") Annual Energy Outlook ("AEO") gas price projections, rather than DESC's approach of escalating from current price points.[11] DESC will not experience different natural gas prices in the context of avoided costs than it will in the context of integrated resource planning; thus, to ensure consistency, the Company should use the same, Commission-approved methodology for forecasting gas prices in IRP and avoided cost modeling exercises.

Figure 1 below shows DESC's gas price forecast along with a blended forecast that I recommend DESC use to recalculate its avoided energy rates. The blended forecast directly utilizes the most recent AEO Reference case prices, with the exception of the first two years. In year one, the NYMEX futures price from DESC's proposal is used, and in year two, the midpoint between the NYMEX price and the AEO price is used. Year three and beyond directly used the AEO prices. The blended forecast achieves an appropriate balance between short-term futures market indicators and long-term gas supply and demand dynamics. The blended forecast is also consistent with previous Commission orders. Notably, the gas price forecast DESC is currently using to calculate avoided energy is on average 12% below the blended forecast, which means that adopting the more reasonable blended NYMEX-AEO forecast would likely have a pronounced impact on the avoided energy rates.

Figure 1: Natural Gas Price Assumptions

[10] DESC Response to CCL/SACE Data Request 2-1, attached as **Exhibit KS-2**.
[11] Commission Order No. 2020-832 at 70-71, Docket No. 2019-226-E (Dec. 23, 2020).



Q. DID DESC USE A REASONABLE LOAD FORECAST IN ITS PROPOSAL?

A. No. I compared the load forecast DESC used in its production cost modeling with the base case load forecast from DESC's Modified 2020 IRP, which this Commission approved on June 2, 2021.[12] I found that on average, the megawatt-hour sales forecast used to calculate the avoided energy costs was 1.2% below the Modified IRP forecast, and the peak demand forecast was 2% below the Modified IRP forecast. [13] Even if these differences are not large, they are still material because lower load assumptions may suppress avoided energy rates by reducing the price of the generating unit that is avoided by the QF in the production cost modeling. Similar to gas prices, the Company should use a consistent methodology and inputs for load forecasts across avoided cost and IRP modeling exercises. DESC's avoided cost proposal was filed just several months after the Company filed its Modified 2020 IRP, and I would not expect material changes to occur within the load forecast in such a timespan.

[12] Commission Order No. 2021-429, Docket No. 2019-226-E (June 18, 2021).
[13] *See* DESC Response to CCL/SACE Data Request 2-2 (showing 40 years of hourly system load).

Q. HAS DESC INCLUDED IN ITS FILINGS THE INFORMATION NEEDED TO DETERMINE WHETHER THE PRICING PERIODS ARE REASONABLE?

A. No.

Q. WHY IS IT IMPORTANT TO HAVE THE UNDERLYING ASSUMPTIONS FOR THE PRICING PERIODS?

A. If the pricing periods are not well aligned with DESC's system costs, then the rates will not "fully and accurately reflect the electrical utility's avoided costs."

Q. ARE DESC'S PRICING PERIODS ALIGNED WITH DESC'S SYSTEM COSTS?

A. It is not possible to determine whether DESC's pricing periods align with DESC's system costs based on DESC's filings. In my opinion, DESC did not provide adequate support for its pricing periods in its application and testimony to allow for independent review and verification of the underlying assumptions, data, and results. This is especially concerning given the Commission's requirement in Order No. 2019-847 that in the future, the selection of pricing periods should be supported:

> The independent consultant recommends that DESC provide support for the pricing periods that it employs in its next avoided cost filing. We agree. While the record did not sufficiently evidence that the DESC pricing periods were actually biased or inappropriate, the risk of – at a minimum – inaccuracies due to the broad pricing periods is significant. Accordingly, additional justification for pricing periods should be presented in future filings.[14]

Notably, DESC's current proposal is such a "future filing," and DESC has not provided this additional justification.

[14] Commission Order No. 2019-847 at 26, Docket No. 2019-184-E (Dec. 9, 2019).

Q. IS THERE ANYTHING ELSE YOU WOULD LIKE TO SAY ABOUT DESC'S PROPOSED PRICING PERIODS?

A. DESC Witness Eric Bell testified that "DESC has included time periods for these non-solar avoided costs rates based on an analysis of the hourly marginal costs. Logical grouping of hours of the day and season by marginal cost value produced eleven time periods for PR–Standard Offer non-solar, which was simplified to four time periods for PR-1 non-solar."[15] However, Witness Bell does not present the analysis referenced to support this claim.

DESC appears to view a "heat map" provided in discovery as justification, though it did not make this clear in the discovery response. In the DESC supplemental response to ORS Audit Information Request ("AIR") 1-4, DESC provided hourly system marginal cost data from PLEXOS, and included a 12 x 24 heat map matrix of average LMPs for each month of the year and hour of the day. While this heat map is not described or labeled as to explain its purpose or justify its use as a basis for designating pricing periods, a subsequent discovery question seems to indicate that DESC views this heat map as the "analysis of the hourly marginal costs" referenced by Witness Bell.[16]

In any case, the heat map uses a coloration scheme whereby high prices are colored red, medium prices are colored yellow, and low prices are colored green. However, a close review reveals that in fact there are numerous instances across the heat map where this coloration scheme is inconsistent or unclear. For example, a price of $32.45 is colored red in one place while a price of $32.53 is colored light green in another. In another example,

[15] Direct Testimony of Eric Bell at 35, Docket No. 2021-88-E (June 29, 2021).
[16] *See* DESC Supp. Response to AIR 1-4; DESC Response to CCL/SACE Data Request 2-11. The heat map provided in these discovery responses is attached as **Exhibit KS-3**.

$29.05 is orange in one place and $29.11 is green in another. In other words, at best, it's unclear what the colors on the heat map are supposed to indicate because similarly colored areas do not necessarily correspond to similar prices. Further, even if the colors in DESC's heat map are taken at face value, it is not at all clear from consulting the heat map that the pricing periods selected actually align with the color pattern in a reasonable way. Yet another concern about the heat map is that confirming or denying whether the hourly marginal price projections used to create the heat map are themselves reasonable is an important step in verifying any methodology that makes use of these prices. However, in this case the price projections were not accompanied by corresponding hourly load data or hourly dispatch data, and therefore could not be verified.[17]

In sum, whether this heat map can even be legitimately considered as attempted support for DESC's pricing period selections is questionable. But even if it is considered as such, the information content of the heat map is flawed and the conclusions drawn from it are highly likely to be flawed as well. I view this aspect of DESC's methodology as a potentially biasing factor in DESC's proposed energy rates that could be significantly undermining the goal of fully and accurately reflecting the utility's avoided costs.

Q. PLEASE PROVIDE ADDITIONAL DETAIL ABOUT ELIGIBILITY.

A. In DESC's proposal, standalone solar facilities are eligible only for a "solar QF" energy rate derived by using a solar production profile for the change case simulated in PLEXOS.[18] Under this rate, solar QFs are paid a flat energy rate for all energy produced during a given year,[19] regardless of the seasonal or hourly timing of the energy production

[17] In a follow-up data request, CCL/SACE obtained these data on July 19, 2021. *See* DESC Response to CCL/SACE Data Request 3-1.
[18] Direct Testimony of James Neely at 8, Docket No. 2021-88-E (June 29, 2021).
[19] *Id.* at 13 (Table 3).

and regardless of whether the production profile of a given individual QF actually aligns well with the production profile assumed by DESC in developing the solar QF energy rate. As a consequence, for some and possibly all solar QFs, avoided energy rates may not "fully and accurately reflect the electrical utility's avoided costs," since seasonal and hourly solar production can vary materially across different locations and technology types, such as fixed-tilt versus single- or dual-axis tracking, and across other factors. The approach of restricting standalone solar eligibility to this solar QF rate also will not capture any differentiation in QF avoided costs "based on the geographic location and resource type of a small power producer's qualifying small power production facility" as supported by the EFA. Instead, regardless of where solar QFs are located or how their systems are designed, all solar QFs will be paid the same flat energy rates.

Q. WHAT OTHER QF RATE APPROACHES IS DESC PROPOSING?

A. DESC is proposing another avoided energy rate, for which all other QFs (but not standalone solar QFs) would be eligible. DESC refers to this rate as the "non-solar QF" energy rate. This is essentially a technology-neutral rate design whereby any type of QF can generate energy and be paid based on the value of the energy to system at that time. Under this technology-neutral rate approach, the pricing periods I described above are used to designate different energy rates for different time periods based on the corresponding energy value to the DESC system during those time periods.[20] Thus, in contrast to the solar QF energy rate, the technology-neutral energy rate would compensate each standalone solar QF more appropriately based on its unique production profile—that is, the seasonal and hourly pattern of generation—which again can vary based on geographic location and

[20] *Id.* at 8, 12 (Table 1).

technology choices such as fixed-tilt versus tracking technology options. This approach would better reflect the utility's avoided costs. Additionally, the price signals under the technology-neutral energy rate would incentivize project developers for standalone solar QFs to design and site projects in way that maximizes system value, thereby further helping to keep electric rates lower for customers.

Based on these observations, I believe restricting standalone solar QFs to the solar QF rate would not "treat small power producers on a fair and equal footing with electrical utility-owned resources" as required by the EFA. Moreover, in Order No. 2020-244, this Commission rejected a solar-specific energy rate and instead ordered DESC to make standalone solar QFs eligible for a technology-neutral rate (which used essentially the same approach as the "non-solar QF" rates proposed here).[21]

Q. DOES DESC PROVIDE ANY RATIONALE FOR RESTRICTING ELIGIBILITY FOR STANDALONE SOLAR QFS?

A. Witness Bell discusses the Company's views on the need for the solar-specific rates,[22] summarizing that "solar generation is limited in dispatchability and flexibility, and subject to intermittency and time-of-day restrictions."[23] Witness Bell also maintains that "[t]he value of solar decreases as more is added to the system because there will be an oversupply in certain low-load conditions due to the fact that solar cannot be reduced or curtailed."[24]

Q. DO YOU AGREE THAT THESE ARE VALID REASONS TO RESTRICT STANDALONE SOLAR QF ELIGIBILITY?

[21] Commission Order No. 2020-244 at 7-9, Docket No. 2019-184-E (Mar. 24, 2020).
[22] Direct Testimony of Eric Bell at 31-33, Docket No. 2021-88-E (June 29, 2021).
[23] *Id.* at 34.
[24] *Id.* at 32-33.

A. No. Even taking these claims at face value, other elements of DESC's proposal and South Carolina's PURPA implementation already account for the production patterns of standalone solar, and make DESC's technology-neutral approach well-suited to standalone solar. DESC is proposing a variable integration charge, which if approved would account for any material intermittency and operating reserves cost impacts deemed legitimate by the Commission. Use of the PLEXOS hourly production cost model representing the Company's existing and future generators and existing solar PPAs accounts for the impact of existing solar on system marginal costs. Regarding limitations in dispatchability and flexibility, and time-of-day restrictions, under the technology-neutral rate approach, the QF is compensated for energy production based on when it is produced. During hours of lower system value, by definition QFs are paid a lower energy rate, whereas during hours of higher system value, QFs are paid a higher energy rate. Standalone solar would be compensated based on when it generates electricity, and would not be paid when it is not generating. Contrary to Witness Bell's statement, solar QFs can be "reduced or curtailed" if such action is unavoidable for reliability purposes, and during "low-load" periods the technology-neutral energy rates recognize and pay a lower value for any solar QF production that the system does use. Finally, under the EFA, the South Carolina General Assembly established a minimum biannual frequency of updating avoided cost rates.[25] This ensures that a utility will not be locked into offering rates that do not reflect the current needs of the utility system and operating environment. In sum, there are no real issues specific to standalone solar PV that necessitate a solar-specific rate.

[25] S.C. Code Ann. § 58-41-20 (A).

Q. ARE THERE FURTHER POTENTIAL IMPROVEMENTS TO PRICE SIGNALS AND DIFFERENTIATING QF AVOIDED COSTS?

A. Yes. Compared to the general approach of the technology-neutral energy rates, it is possible to create even better price signals for QF developers, and to further specify QF avoided costs "based on the geographic location and resource type of a small power producer's qualifying small power production facility." This could be achieved through a locational marginal pricing system, such as those used by all seven regional transmission organizations ("RTOs") across the United States. With LMP, pricing could take on not just a temporal component but also a spatial component, thereby incentivizing QF project design and siting towards the most valuable locations on the grid in addition to the most valuable times.

Q. DO YOU HAVE ANY ADDITIONAL COMMENTS ABOUT DESC'S PROPOSED AVOIDED ENERGY RATES?

A. Yes. As I noted above, vetting production cost modeling assumptions and results is critical to understanding whether avoided cost rate proposals are reasonable. This includes fuel price, load, and generating unit inputs as well as the resulting system dispatch data. One electric sector practice that has emerged in recent years that makes such energy modeling reviews important is the uneconomic dispatch of expensive coal generation. In essence, utilities have been found to run coal units even when it would be lower cost to utilize another resource to meet demand at a given time. This practice can greatly impact avoided cost assessments because if more expensive units are designated as "must-run" or otherwise operated out of economic merit order, then there may be many hours in which lower cost units will be the marginal units that set the avoided cost rates, thereby effectively

suppressing prices and resulting in unreasonably low rates. I recommend evaluating energy modeling assumptions and results to assess how coal units are being simulated and whether this is inappropriately impacting calculated avoided cost rates.

On DESC's system specifically, there are indications that their coal plants are expensive relative to other generation options, yet DESC stated that the Williams coal plant is designated as must-run in its PLEXOS modeling. [26] This practice should be evaluated closely to determine if it is inappropriately impacting avoided costs. Additionally, independent modeling by an intervenor in DESC's 2020 IRP proceeding found that accelerated retirement of coal units is cost-competitive with other resource plans, suggesting that these plants are expensive relative to other generation options.[27]

Q. PLEASE PROVIDE YOUR CONCLUSIONS AND RECOMMENDATIONS ON DESC'S AVOIDED ENERGY RATE PROPOSALS.

A. DESC'S avoided energy rate proposals fail to accurately reflect DESC's avoided costs as required by the EFA, given that the gas prices and load assumptions, and possibly also the pricing periods, are unreasonable and unsupported. In addition, the eligibility restriction proposed by DESC would be discriminatory against small power producers.

As a result, I recommend that key inputs to the avoided energy calculations be revised—in particular, natural gas prices and load forecast. I also recommend that clear analytical support be provided for the pricing periods implemented. Finally, I recommend that standalone solar QFs be granted eligibility for the technology-neutral energy rates.

III. AVOIDED CAPACITY RATES

[26] DESC Response to CCL/SACE Data Request 2-5, attached as **Exhibit KS-4**.
[27] Direct Testimony of Derek Stenclik at 34-35, Docket No. 2019-226-E (July 10, 2020).

Q. WHAT CONCERNS DO YOU HAVE WITH DESC'S PROPOSED AVOIDED CAPACITY RATES?

A. I have several concerns with DESC's proposed avoided capacity rates. First, I will address an element of the avoided capacity calculations relating to generating facility availability, which I believe is in violation of the EFA and PURPA's nondiscriminatory standard and does not align with the EFA requirement that "the commission shall treat small power producers on a fair and equal footing with electrical utility-owned resources…." Second, I view the capital cost assumptions used in DESC's calculation as unreasonable, which compromises the goal of fully and accurately reflecting DESC's avoided costs. And third, I have concerns with the capacity accreditation and allocation approaches DESC proposes.

Q. PLEASE PROVIDE ADDITIONAL DETAIL ABOUT THE CALCULATIONS RELATING TO GENERATING FACILITY AVAILABILITY.

A. Under DESC's approach for calculating avoided capacity payments, QFs would only be compensated at the full avoided capacity rate if they generate during all avoided capacity payment hours. Importantly, however, this is not true of utility owned resources. All technologies are subject to forced outages, and sometimes those outages occur during peak periods when system capacity is most needed. Despite this limitation, utility-owned generating units are not penalized in terms of cost recovery; that is, utility-owned assets are granted full cost recovery when they are deemed prudently built and operated, and when they are used and useful, even if they experience forced outages, including during periods of peak demand. In order to treat QFs on a fair and equal footing with utility-owned resources, QFs should be compensated in such a way that allows for a level of

unavailability that is reasonably comparable to the level of unavailability of utility-owned resources. Applying a "performance adjustment factor" ("PAF") within the avoided capacity rate calculations would accomplish this goal.

Q. WHAT IS A PERFORMANCE ADJUSTMENT FACTOR AND HOW COULD IT BE APPLIED WITHIN DESC'S CALCULATIONS?

A. A PAF is a multiplier that can be easily incorporated into avoided capacity calculations to allow for a reasonable level of generator unavailability while still providing full compensation for cost recovery purposes, which as described above is how utility-owned generators are treated. A PAF is typically based on a measure of utility generator availability such as annual forced outage rate. For example, Duke Energy included a PAF of 1.05 in its 2019 avoided cost rate proposal, which this Commission approved: "The performance adjustment factor capacity payment multiplier proposed by Duke is reasonable and supports Act 62's objective of placing QF generators and utility generators on equal footing in terms of reasonable allowance for unplanned outages."[28] I recommend that DESC apply the same 1.05 PAF to its avoided capacity calculations in this docket.

Q. DO YOU HAVE ANY COMMENTS ABOUT DESC'S PROPOSED CAPACITY PAYMENTS UNDER THE TECHNOLOGY-NEUTRAL TARIFF?

A. DESC's proposed technology-neutral tariff requires that QFs be available and dispatchable in *all* capacity payment hours to receive *any* capacity payment.[29] To place QFs on equal footing with utility-owned generation, there should be no such requirement in this tariff. Utilities are not compensated any less as a consequence of utility-owned coal- or gas-fired generating units experiencing forced outages, even in the middle of peak

[28] Commission Order No. 2019-881(A) at 30, Docket Nos. 2019-185-E, 2019-186-E (Jan. 2, 2020).
[29] Direct Testimony of Allen Rooks, Exhibit AWR-5 at 3, Docket. 2021-88-E (June 29, 2021).

demand hours. QFs should be paid based on their availability during the capacity payment hours, and if they are available for part of those hours, they should be paid proportionally.

The Commission approved Duke Energy Carolinas and Duke Energy Progress technology-neutral avoided cost tariffs[30] in Docket Nos. 2019-185-E and 2019-186-E; importantly, those tariffs did not include any availability or dispatchability requirements as proposed by DESC here.

Q. PLEASE PROVIDE ADDITIONAL DETAIL ABOUT THE CAPITAL COST ASSUMPTIONS.

A. DESC's avoided capacity calculations assume a 991 $/kW capital cost (2020 dollars) for aeroderivative combustion turbine ("aero-CT") technology, and 8.14 $/kW-year fixed O&M cost.[31] I compared this value to a highly regarded public reference, and found that DESC's capital cost and fixed O&M designation for aero-CT technology was materially lower. The EIA report on Capital Cost and Performance Characteristics,[32] prepared by engineering firm Sargent & Lundy, indicates a capital cost of 1139 $/kW and fixed O&M of 15.79 $/kW-year, after adjusting for inflation and locational factors. Compared to this benchmark, DESC's current assumptions are unreasonably low—by about 13% for capital cost and 48% for O&M—and may as a result fail to "fully and accurately reflect the electrical utility's avoided costs."

I note that in Order No. 2020-832 in DESC's IRP proceeding, the Commission rejected DESC's proposed assumption for combustion turbine capital costs in favor of

[30] DEC Schedule PP (SC) and DEP SC Schedule PP-5, Docket Nos. 2019-185-E, 2019-186-E (Jan. 17, 2020).
[31] DESC Response to ORS AIR 1-4, "Capacity Cost Base v Change –AeroCT_10_66MW.xlsm."
[32] US EIA. Capital Costs and Performance Characteristics for Utility Scale Power Generating Technologies (Washington DC, February 2020).

using a respected public industry data source, in that case the National Renewable Energy Lab's Annual Technology Baseline ("ATB").[33] While the ATB does not include cost data or projections for aero-CTs, EIA is a similar and highly credible public reference source—indeed, in the same order the PSC required DESC to use EIA assumptions for natural gas prices. I recommend that DESC be required to use the EIA data points for the aero-CT capital cost and fixed O&M.

When substituting the EIA values into DESC's spreadsheet, I obtain an avoided capacity cost of 60.27 $/kW-year, up from DESC's proposed 49.89 $/kW-year. Further, applying the 1.05 PAF recommended above, the total avoided capacity cost increases to 63.29 $/kW-year.

Q. HOW DOES DESC INCORPORATE THE CAPITAL COST CALCULATIONS INTO ITS PROPOSED RATES?

A. Similar to the proposed avoided energy rates discussed above, DESC is proposing separate "solar QF" avoided capacity rates and "non-solar QF" (that is, technology-neutral) avoided capacity rates. In the solar QF avoided capacity rates, DESC applies a capacity accreditation factor to the calculated capital cost value and spreads the resulting avoided capacity cost across an entire year of solar PV generation.[34] In the technology neutral avoided capacity rates, DESC allocates the calculated capital cost value to seasons and then further spreads the resulting avoided capacity cost across a limited number of hours intended to cover the times of greatest capacity need on the DESC system.[35] While these

[33] Commission Order No. 2020-832 at 54-56, Docket No. 2019-226-E (Dec. 23, 2020).
[34] Direct Testimony of James Neely at 10, Docket No. 2021-88-E (June 29, 2021).
[35] *Id.* at 9-10.

are both reasonable overall approaches to incorporating avoided capacity value into a QF rate, I identified numerous problems with the particulars of DESC's methodologies.

For clarity, the PAF discussed above is a multiplier applied to the final $/kW-year capital cost value to put QFs on equal footing with utility-owned resources, whereas the accreditation factor and seasonal/hourly allocations noted here ultimately determine how much of that adjusted $/kW-year value a QF can access and when the QF must generate in order to access capacity payments.

Q. WHAT IS CAPACITY ACCREDITATION?

A. Capacity accreditation is the process by which generating technologies are assigned a capacity credit relative to their nameplate capacity. Solar PV typically is not designated as contributing its entire nameplate capacity rating towards meeting resource adequacy needs. A 100 MW solar PV facility, for example, may receive a 50% capacity accreditation, which would designate that the system can count on 50 MW rather than the full 100 MW for resource adequacy purposes.

Q. WHAT APPROACH DID DESC USE FOR CAPACITY ACCREDITATION?

A. Within the solar QF capacity rates, DESC uses an effective load carrying capability ("ELCC") methodology for capacity accreditation purposes. I broadly agree that an ELCC approach is reasonable and view such an approach as an improvement on DESC's previous approach to solar accreditation.[36] However, the ELCC approach encompasses a complex set of data inputs and calculations. If those data inputs and calculations are not reasonable, then the ELCC result will be flawed. Unfortunately, assessing DESC's application of the

[36] That is, the approach DESC proposed in Docket No. 2019-184-E, which this Commission rejected.

ELCC method was not possible with the information DESC provided in its application, testimony, and initial discovery responses. DESC Witness James Neely provide a two-page summary of the ELCC analysis,[37] and in initial discovery DESC provided a similar, extremely brief overview of the methodology along with the results of its analysis;[38] however, those descriptions fell far short of the detail needed to actually evaluate the analysis. Of further concern is DESC's reference within this brief overview to studies presented in a previous docket,[39] suggesting that potentially much of the basis of DESC's current ELCC result is prior analyses using old data inputs. DESC also noted in its initial discovery response that "[t]his is not a spreadsheet because this calculation was done in SAS." DESC provided additional detail and data inputs in a follow-up data request received on July 19, 2021.[40] That response provided in some respects a slightly more detailed description of the analysis, the actual SAS code noted previously, and several datasets used as inputs within the analysis.

Q. WHAT ASSESSMENT CAN YOU MAKE BASED ON THE INFORMATION YOU DO HAVE ABOUT DESC'S ELCC ANALYSIS?

A. I am concerned about both the lack of rigor of DESC's ELCC calculation and a failure to incorporate current best practices in ELCC study design. I am also troubled that much of the substance of the analysis is effectively not reviewable, because it is represented in a software program that is not accessible without a license and detailed knowledge of the SAS product, rather than being documented openly in a typical report format.

[37] Direct Testimony of James Neely at 10, Exhibit JWN-1, Docket 2021-88-E (June 29, 2021).
[38] DESC Response to ORS AIR 1-4, "ELCC 100MW.docx," attached as **Exhibit KS-5**.
[39] Specifically, the 2019 DESC avoided cost proceeding, Docket No. 2019-184-E.
[40] *Compare* **Exhibit KS-5**, *with* DESC Response to CCL/SACE Data Request 2-9, attached as **Exhibit KS-6**.

Q. PLEASE DISCUSS THE LACK OF RIGOR AND FAILURE TO INCORPORATE BEST PRACTICES.

A. The datasets DESC provided consist of a single year of solar PV generation data, two years of hourly load data spanning months in 2016, 2017, and 2018, and annual forced outage rates for DESC's system generating units. In contrast, industry standard approaches use complex statistical and probability-based methods, large datasets for a variety of inputs, and simulate thousands of iterations to yield more robust results. For example, E3 used its RECAP model in an ELCC analysis for NorthWestern Energy, reporting that "RECAP evaluates adequacy through time-sequential simulations over thousands of years of plausible load, renewable, hydro, and stochastic forced outage conditions." [41] In another example, an ELCC study for the Southwest Power Pool RTO describes the following methodology:

> Twenty (20) random seed representations and seven probabilistically weighted load forecast uncertainty (LFU) levels were applied to each scenario to create additional variation in unit availability and dispatch between simulations. This is defined as one case. Fifty (50) iterations were applied to each case to reach statistical convergence and reduce the standard error between results. In total, 7,000 iterations (50 iterations * 20 seed values * 7 LFU levels) were applied to each wind scenario. [42]

More fundamentally, DESC's application of ELCC is not consistently integrated into its overall resource adequacy approach, and does not appear to incorporate best practices from this evolving field. In a recent white paper on ELCC,[43] E3 notes that "The

[41] Arne Olson *et al.*, NorthWestern Energy Incremental ELCC Study at 6 (July 2020).
[42] SPP Resource Adequacy, ELCC Wind Study Report at 9 (Aug. 13, 2019) .
[43] N. Schlag, Z. Ming, A. Olson, L. Alagappan, B. Carron, K. Steinberger, and H. Jiang, *Capacity and Reliability Planning in the Era of Decarbonization: Practical Application of Effective Load Carrying Capability in Resource Adequacy*, Energy and Environmental Economics, Inc. (Aug. 2020).

application of ELCC in resource adequacy planning requires a carefully considered framework, both for vertically integrated utilities responsible for meeting their own resource adequacy needs and for centralized resource adequacy programs and capacity markets."[44] The paper discusses at length that one of the strengths of ELCC is representing interactive effects such as the benefits of resource diversity. For instance,

> [w]hile resources with similar operating characteristics yield diminishing returns, combining resources with complementary characteristics can produce the opposite effect, a total ELCC that is greater than the sum of its parts. This effect has commonly been described as a "diversity benefit" in jurisdictions that have explored ELCC implementation. There are many combinations of resources that will produce such an effect; solar and storage provide an intuitive illustration. This is because solar acts to "sharpen" the shape of the net peak demand, reducing the length of the period during which storage must discharge to reduce the peak, in addition to providing a source of energy for charging.[45]

While DESC has considerable energy storage and demand response on its system,[46] I do not see any indication that DESC's use of ELCC is properly characterizing the interactive effects of solar PV, storage, and demand response. Battery storage may soon be added to DESC's system as well given that battery technology costs continue to decline, but there is no sign that DESC's ELCC application accounts for diversity benefits from those resources interacting with others like solar PV.

Q. DO YOU HAVE ANY OTHER CONCERNS ABOUT DESC'S ELCC ANALYSIS?

[44] *Id.* at 9.
[45] *Id.* at 6.
[46] Almost 600 MW of pumped hydro storage, and several hundred MWs of demand response. DESC Modified 2020 IRP at 17, 143, Docket No. 2019-226-E (Feb. 19, 2021).

A. Yes. I am concerned that due to the issues I have just discussed, DESC's ELCC results may be undervaluing solar PV and thus failing to "fully and accurately reflect the electrical utility's avoided costs." A recent Lawrence Berkeley National Laboratory ("LBNL") study[47] on solar and storage capacity accreditation included calculations of solar capacity credits for several Florida utilities.[48] The results are displayed in Figure 2 below.

Figure 2: LBNL Solar PV Capacity Credits for Florida Utilities

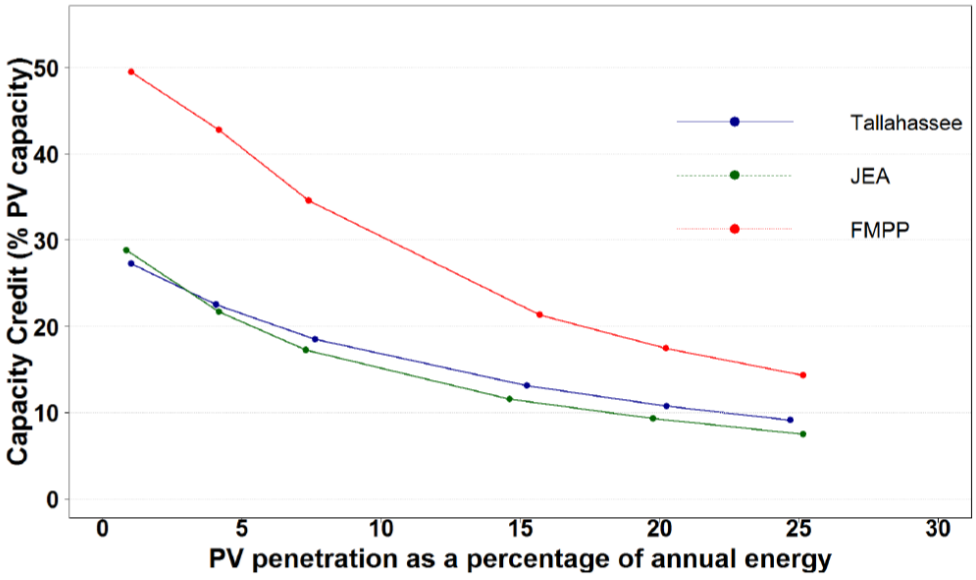


Figure 2 shows that at 10% PV penetration on an energy basis, which is approximately DESC's level of solar PV today, two of the three utilities have a solar PV capacity credit between 15% and 20%, and the third is around 30%. In contrast, DESC's ELCC calculation result is a 5% capacity credit for solar PV.[49]

An additional concern about DESC's ELCC approach is that DESC proposes to apply a single ELCC uniformly across all solar PV facilities in its solar QF capacity rate.

[47] A. Mills and P. Rodriguez. Drivers of the Resource Adequacy Contribution of Solar and Storage for Florida Municipal Utilities (October 2019).
[48] *Id.* at 9.
[49] Direct Testimony of James Neely at 10, Docket. No. 2021-88-E (June 29, 2021).

That ELCC is based on a particular solar production curve, and thus cannot capture the variation in solar QFs due to location and system design choices. This problem is analogous to the solar QF energy rate issue I discussed above, where DESC's approach does not capture any differentiation in QF avoided costs "based on the geographic location and resource type of a small power producer's qualifying small power production facility."

Q. WHAT ARE YOUR CONCLUSIONS ABOUT DESC'S ELCC ANALYSIS?

A. DESC's 2021 ELCC analysis cannot be fully evaluated due to use of opaque SAS code, but based on the elements that can be assessed, it does not clear the bar of further advancing the rigor and accuracy of this important component of avoided cost calculations. It is thus not surprising that DESC's ELCC result is not consistent with those included in a respected organization's study of peer Southeastern utility systems. DESC's proposal also is not designed to compensate different solar QFs different amounts for capacity in such a way that accounts for geographic and resource type attributes. I propose an alternative below that meets all of these goals.

Q. PLEASE DESCRIBE THE TECHNOLOGY-NEUTRAL AVOIDED CAPACITY RATE THAT DESC IS ALSO PROPOSING.

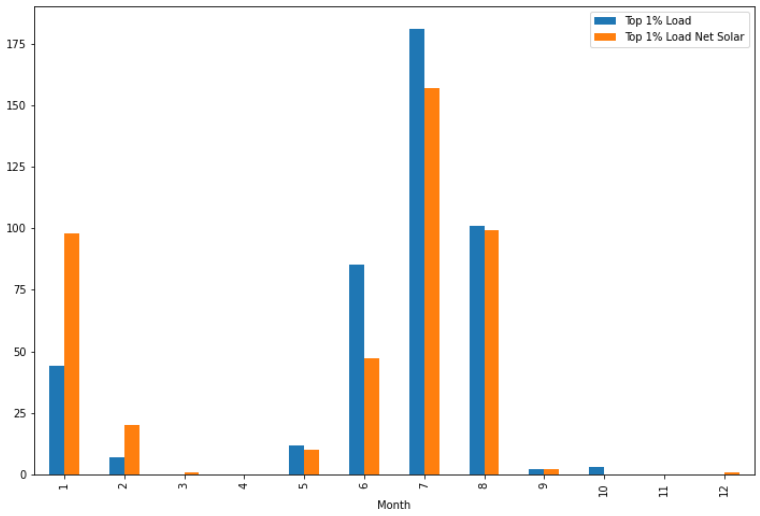
A. As I mentioned previously, in addition to "solar QF" avoided capacity rates, DESC is also proposing "non-solar QF" (that is, technology-neutral) avoided capacity rates, for which standalone solar would not be eligible. These rates also suffer from serious flaws. The main flaw in the technology-neutral capacity rates is that DESC allocates all capacity value to a three-hour period during the winter season.[50] The Company does not provide any basis in testimony or initial discovery for this assumption. In follow-up discovery, the

[50] *Id.* at 9-10.

Company provided several qualitative statements on winter capacity needs and workpapers related to the timing of peak hours during winter days.[51] However, given that DESC has experienced more summer peaks in the last decade than winter peaks,[52] assigning all capacity value to winter hours is questionable. In fact, as illustrated in Figure 3 below, the DESC system experiences very large numbers of high-demand hours during the summer season, even after accounting for the solar PV facilities already operating and contracted. The blue bars in Figure 3 show the top 1% of gross loads during the last three years for which data are available, illustrating that far more high-demand hours occur during the summer months of June, July and August than during the winter months of December, January, and February. The orange bars in Figure 3 show the same data points but subtracting generation from an assumed 973 MW of solar PV facilities—that is, the top 1% net load hours accounting for existing solar. While the existing solar on the DESC system has pushed the number of high-demand net load hours more towards the winter season, there are still more high-demand hours during the summer than during the winter. These data suggest that assigning all capacity value to winter hours is inappropriate.

Figure 3: Top 1% Demand Hour Count on DESC System, 2017-2019

[51] DESC Response to CCL/SACE Data Request 2-10, attached as **Exhibit KS-7**.
[52] *See* Direct Testimony of Derek Stenclik at 20 (Figure 6), Docket No. 2019-226-E (July 10, 2020).



Similar to the ELCC issues, the capacity allocation elements of DESC's proposal raise the possibility that the lack of an underlying analysis or a flawed underlying analysis is in turn resulting in another failure to "fully and accurately reflect the electrical utility's avoided costs."

Q. IS THERE A READILY AVAILABLE IMPROVEMENT FOR DESC'S FLAWED CAPACITY ALLOCATION WITHIN ITS TECHNOLOGY-NEUTRAL CAPACITY RATES?

A. Yes. It is straightforward to design a technology neutral rate using public data that appropriately recognizes the fact that the DESC system sometimes peaks in the summer and sometimes peaks in the winter, and furthermore experiences large numbers of high load hours in the summer months, as illustrated in Figure 3 above.

I used the five most recent years of historical hourly load data to identify the top 1% of net load hours after subtracting 973 MW of solar generation. I then identified winter and summer allocation factors using the average load values for those top 1% hours, thereby designating a winter allocation of 52% and a summer allocation of 48%. I consider

this to be a conservative seasonal allocation because I assigned shoulder season values from months such as March and October to the winter season, and also because the count of the top 1% net load hours is actually more heavily weighted towards the summer, with about 69% of top 1% net load hours occurring in the summer months.

Next I used those counts of top 1% net load hours to identify the particular hours during the winter and summer months where much of the top 1% net loads occur, and designated winter hours of 6am to 9am during January and February, and summer hours of 2pm to 8pm during June, July and August as appropriate peak hours.

Finally, I spread the total avoided capacity cost of 63.29 $/kW-year (derived above) across seasons and hours using those designations just described. Table 1 shows the updated technology neutral capacity rates I recommend for adoption.

Table 1: CCL/SACE Revised Technology-Neutral Avoided Capacity Rates

Time Period	$/kWh
January, February 6am to 9am	0.18535
June, July, August 2pm to 8pm	0.05522

I also evaluated an example single-axis tracking solar PV plant located in the Aiken area for capacity payments under this rate design, and found that the plant would receive about 19% of the possible capacity value represented in these rates. I note this is substantially higher than the 5% capacity credit level proposed by DESC in its ELCC application, and it is intuitive that a methodology that recognizes summer capacity value would result in higher capacity credits to solar PV QFs. The 19% capacity credit is also in line with the regional capacity credits calculated by a highly regarded national lab, LBNL, as cited above.

Q. IS THERE ANY REASON STANDALONE SOLAR QFS SHOULD NOT BE ELIGIBLE FOR THE TECHNOLOGY-NEUTRAL CAPACITY RATES?

A. No. Similar to the technology-neutral energy rates discussed above, the rates create a performance-based system whereby QFs that generate power during the designated peak seasons and hours are paid an appropriate amount, and QFs that do not generate during those hours are not paid. This system works equally well for standalone solar and other technologies. Also, again like the technology-neutral energy rates, these rates are capable of recognizing differences in QF avoided costs based on geographic location and resource type, unlike DESC's ELCC-based capacity rate proposal.

It is worth noting that this Commission approved DEC's and DEP's technology neutral avoided capacity rates in Order No. 2019-881(A),[53] which are currently in effect, and for which standalone solar QFs are eligible. Further, those rates allocate partial capacity value to the winter season and partial capacity value to the summer season,[54] as I am proposing here.

Q. DO YOU HAVE ANY OTHER COMMENTS ON DESC'S AVOIDED CAPACITY RATE PROPOSALS?

A. It is clear from DESC's avoided capacity rate proposals—both the ELCC-based solar QF rate and the technology neutral rate that assumes no summer capacity value—that the Company's approach to resource adequacy is seriously deficient. This is a key topic that spans not just avoided cost but many other important regulatory venues, such as integrated resource planning, DSM planning, and distributed energy resource policy. Because of the importance of this issue to both DESC's 2023 IRP and its future avoided

[53] Commission Order No. 2019-881(A) at 167-168, Docket Nos. 2019-185-E, 2019-186-E (Jan. 2, 2020).
[54] *Id.* at 30-31; *see also id.* Exhibit 1.

cost filings, this issue should also be an issue of particular concern for the Commission and I recommend that it be specifically addressed as part of the DESC IRP stakeholder group or similar process.

Q. PLEASE PROVIDE YOUR CONCLUSIONS AND RECOMMENDATIONS ON DESC'S AVOIDED CAPACITY RATE PROPOSALS.

A. DESC's avoided capacity rates do not put small power producers on equal footing with utility-owned resources as required by the EFA, due to omission of a PAF and the requirement to be available during all capacity hours. In addition, the avoided capacity cost calculation uses unreasonably low input assumptions, such that the resulting rates do not accurately reflect DESC's avoided costs. Lastly, the solar QF rate ELCC application and technology-neutral rate allocation of capacity value are likely undermining accurate reflection of utility avoided costs in rates; the solar QF rate ELCC application was not transparently explained in initial filings (and is still lacking even with later-provided additional information) and the technology-neutral rate allocation of capacity value entirely to winter mornings is not quantitatively supported.

To remedy these aspects of DESC's avoided capacity rates, I recommend use of a PAF and elimination of the tariff provision requiring availability in all capacity hours, as discussed above. I further recommend updating the avoided capacity cost calculation with the specific inputs described above. While it may be reasonable to retain the ELCC rate as an option, I recommend that standalone solar QFs be deemed eligible for the technology-neutral capacity rate coupled with adoption of my revised, analytically supported technology neutral capacity rate.

VI. TRANSPARENCY IN DESC'S APPLICATION AND TESTIMONY

Q. HOW DOES THE EFA ADDRESS TRANSPARENCY?

A. The EFA requires that "[e]ach electrical utility's avoided cost filing must be reasonably transparent so that underlying assumptions, data, and results can be independently reviewed and verified by the parties and the commission."[55]

Q. DOES DESC'S AVOIDED COST FILING MEET THIS STANDARD?

A. In my opinion, it does not. DESC's initial and amended applications, along with its direct testimony, omitted discussion of several underlying inputs, assumptions, and methodologies the Company used to develop its proposal. For example, DESC did not provide key calculation inputs such as gas prices and load forecast assumptions in either its application or testimony. Given the importance of the production cost modeling as described above, this lack of transparency is inconsistent with the EFA provision that "[e]ach electrical utility's avoided cost filing must be reasonably transparent so that underlying assumptions, data, and results can be independently reviewed and verified by the parties and the commission." In order to determine whether DESC has proposed full and accurate avoided cost rates, it is critical to be able to review them and benchmark the assumptions against those approved by the Commission in related proceedings, such as the 2020 IRP proceeding,[56] where the Commission reviewed DESC's system production cost modeling and made numerous determinations on reasonable inputs. Indeed, the General Assembly codified this critical aspect of avoided cost proceedings by explicitly requiring that each avoided cost filing be "reasonably transparent" so as to facilitate an independent review by the parties and the Commission.

[55] S.C. Code Ann. § 58-41-20 (J).
[56] Docket No. 2019-226-E.

DESC also failed to provide these key calculation inputs in response to discovery requests for "a functional copy of the spreadsheets underlying the updated avoided energy, avoided capacity and variable integration charge rates" and for the "supporting calculations for the Company's upcoming proposal."[57] SACE and CCL were forced to send DESC increasingly specific discovery questions to get the information required to review DESC's proposal, an untenable solution given the timeline for this proceeding.

Further, as discussed above, DESC's filings did not sufficiently explain the methodology used to develop its proposed pricing periods. DESC's filings also lacked clarity on which expansion plan DESC used for its PLEXOS runs for production cost modeling, and how it applied the ELCC methodology.

DESC's failure to include this information in its filings hampered my ability to "independently review[] and verif[y]" its proposal. For those reasons, I recommend that the Commission require that DESC include the following information in its next avoided cost application:

- All production cost modeling inputs and outputs, including fuel prices, variable O&M, generating unit operating parameters, load forecasts, hourly avoided cost outputs, and system dispatch data;
- Quantitative analysis and methodologies, with all inputs and outputs, for designating pricing periods;
- Resource expansion plans assumed for both avoided energy and avoided capacity calculations;

[57] ORS AIR 1-3 and 1-4, shown in **Exhibit KS-8**.

- Resource adequacy analyses, with all data inputs and outputs, used to develop avoided capacity rates;
- All workpapers used to calculate avoided energy and capacity rates from underlying production cost and capital cost modeling.

VII. CONCLUSIONS AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR TESTIMONY CONCLUSIONS AND RECOMMENDATIONS.

A. DESC's avoided cost rate proposals fall short of EFA standards due to multiple problems I have identified within the avoided energy and avoided capacity rates. The avoided energy rates use unreasonable gas price and load forecast assumptions. The proposals also discriminate against small power producers by restricting standalone solar eligibility, omitting a PAF, and requiring availability during all capacity hours. Further, the proposals do not accurately reflect utility avoided costs, as required by the EFA, due to the eligibility restrictions, unreasonable inputs to the avoided capacity calculations, and flawed approaches to ELCC and capacity allocation. Lastly, the missing input assumptions and methodological details in DESC's filings, including major production cost model inputs, pricing period development, ELCC calculation details, and the basis of the winter hour capacity allocation, violate the EFA's transparency standard.

To remedy these issues, I recommend revising the gas price and load forecast assumptions, and recalculating the avoided energy rates. I also recommend eliminating all discriminatory elements of the proposal, including the solar QF eligibility restrictions and the availability requirements for capacity payments, as well as adding a PAF. I recommend

updating the capacity cost calculations to use the reasonable inputs proposed in my testimony, and adopting the revised technology-neutral avoided capacity rates that I proposed that appropriately recognize capacity value across the entire year. Finally, I recommend that clarity be provided on the opaque elements and that these elements be reviewed for reasonableness.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CERTIFICATE OF SERVICE

I hereby certify that the parties listed below have been served via first class U.S. Mail or electronic mail with a copy of the *Direct Testimony and Exhibits of Kenneth Sercy* on behalf of the South Carolina Coastal Conservation League and Southern Alliance for Clean Energy.

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This 27th day of July, 2021.

s/Kate Lee Mixson